J. Watada et al. (Eds.)

doi:10.3233/AERD230023

Enumeration Approach in Condensate Banking Study of Gas Condensate Reservoir

Iqmal Irsyad M. FUAD[1], Jang Hyun LEE[1], Berihun Mamo NEGASH[1], Nur Asyraf Md. AKHIR[1]

[1] Petroleum Engineering Department, Universiti Teknologi PETRONAS, 32610 Bandar Seri Iskandar, Perak, Malaysia
{iqmal.irsyad_g03567, lee.janghyun, bmamo.negash, asyraf.akhir}@utp.edu.my

Abstract. This paper presents Enumeration Method in gas condensate reservoir simulation to study the condensate banking complex physics phenomena. Initially, coarse scale grid is commonly used for gas condensate reservoir simulation study. Nevertheless, the coarse scale simulation disregards the condensate bank or it is not able to demonstrate the precise distribution and effects. By introducing Local Grid Refinement (LGR) in simulation model arguably brings a better representation of the condensate bank effect near wellbore but significantly increases the run time. This become severe especially in full field modeling with comingled production. Therefore, enumeration initialization approach was developed to divide the simulation explicitly in coarse scale simulation. During the stops, a region near wellbore was designed where condensate bank parameters were modified based on the history matching. Hence, the drastic change of well performance due to condensate banking could be captured. This drastic change could not physically described in conventional coarse scale simulation model, thus affect prediction accuracy. Comparison between enumeration ways with conventional approach were then investigated. It was found that enumeration method shows a better prediction in investigating the behavior. This is due to its ability to predict mobility changes due to condensate banking, consequently, improve the condensate bank characterization.
Keywords: Gas condensate reservoir, Condensate, Condensate banking, Condensate blockage, Skin, Pressure, Enumeration initialization

1 Introduction

Condensate banking problem is notorious in managing gas condensate reservoirs. Once the flowing bottom hole pressure (FBHP) falls below the dew point pressure, condensate starts to accumulate surround the wellbore and hence reduces the well deliverability [1]. Based on the industry literatures, this reduction in well deliverability cause productivity loss for both gas and condensate for more than 50% [2]. Many reservoirs worldwide are affected, such as the Arun Field in Indonesia, the South Pars Field in Iran, and the Cupiagua Field in Colombia. In view of that, vast studies have been conducted since 1950's to understand and classify the key controlling factors in gas condensate reservoirs' performance below the saturation pressure [3].

Well test analysis and simulation are among the best tools in evaluating reservoir complex system. In 2006, Gringarten introduced four regions developed around the wellbore with diverse fluid saturation from well test analysis, which previously known as two and then three regions by Fevang and Whitson (1996). Fig. 1 displays Gringarten's four regions model for condensate banking description. Closest to the wellbore, Region 1 is the instantaneous vicinity of the well and is characterized by a drop in the liquid saturation and a rise in gas relative permeability at low interfacial tensions (IFT) or high rates [4]. Region 2 is where the liquid saturation reaches a critical value that leads to multiphase fluid flow. Getting further from the wellbore is Region 3 which is a transitional region unveils swift increase in liquid saturation and a consequent drop in gas relative permeability. Liquid in this region is immobile. Away from the well is the Region 4, which is still above the dew point pressure comprises gas with the initial fluid saturation.

Near wellbore, at high velocities, two competing phenomena occurred; inertia and positive coupling [5]–[7]. The inertia effect happens in high fluid velocity and causes additional pressure drop during movement. This effect is named as non-Darcy flow that decrease fluid relative permeability. In contrast, the positive coupling effect causes an increase in relative permeability in IFT as velocity increases and/or IFT decreases [5], [8].

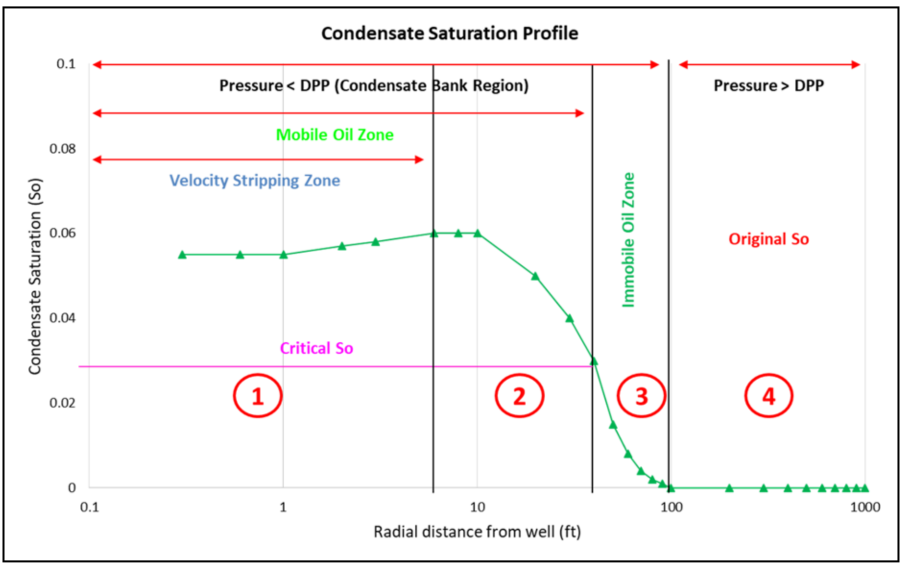

Fig. 1. Gringarten's four regions model for condensate banking description

Fig. 1 can be further expressed in pseudopressure integrals into three parts, corresponding to their flow regions scheme. Eq. (1) demonstrates the superposition of pseudopressure for region 1, 2, 3, and 4 based on their respective flow behavior.

$$\begin{aligned} Total\ \Delta P_p &= \int_{P_{wf}}^{P_R} \left(\frac{k_{rg}}{\mu_g B_g} + \frac{k_{ro}}{\mu_o B_o} R_s \right) dp \\ &= \int_{P_{wf}}^{P^*} \left(\frac{k_{rg}}{\mu_g B_g} + \frac{k_{ro}}{\mu_o B_o} R_s \right) dp + \int_{P^*}^{P_d} \frac{k_{rg}}{\mu_g B_g} dp \\ &+ K_{rg}(S_{wi}) \int_{P_d}^{P_R} \frac{1}{\mu_g B_g} dp \end{aligned} \tag{1}$$

where,

$$Region\ 1\ \&\ 2 = \int_{P_{wf}}^{P^*} \left(\frac{k_{rg}}{\mu_g B_g} + \frac{k_{ro}}{\mu_o B_o} R_s \right) dp +$$

$$Region\ 3 = \int_{P^*}^{P_d} \frac{k_{rg}}{\mu_g B_g} dp +$$

$$Region\ 4 = K_{rg}(S_{wi}) \int_{P_d}^{P_R} \frac{1}{\mu_g B_g} dp$$

The reservoir responses in well testing may be considered for analysis in order to characterize it more appropriately [9]. However well testing could forecast short term performance only [10]. Along with the well test, reservoir simulation is required for long term performance prediction. Also, simulation is a decent tool to characterize a reservoir heterogeneity [11]. At first, coarse scale grid is commonly used for gas condensate reservoir simulation study. However, the coarse scale simulation neglects the condensate bank or it is not able to demonstrate the precise distribution and effects [11]. Accurate assessment of condensate bank can be obtained by using finely gridded simulation model, but it is not recommended in the full-field simulation [11]. Therefore, simulation of gas condensate reservoir remain as the main challenge in the industry.

Most of the simulated models are based on the reduction in gas relative permeability near the wellbore due to condensation of liquid, the skin value and calculated corresponding skin pressure drop. Most of the models after specific period of time reach the stabilization point of condensate drop out recognized by productivity index (PI) graph or/and deliverability curve plot [11]. It means based on the quality of petrophysical properties, after a certain period of time, the PI value reduction rate decreased and that is the time which the skin value will be calculated. Such approaches, however, paucity of studies in describing the shift in relative permeability that affect the pressure drop, as skin is just a composite factor that includes non-ideal flow effects [12]. In addition, there has been no detailed investigation of the condensate development effect; shift in relative permeability to pressure drop. Therefore, the objective of this research is to offer a reliable model that capture significant near well effects due to condensate banking; shift in relative permeability upon production phase and demonstrates the capability of Enumeration Method in defining the gas condensate pressure behaviour.

2 Methodology

Integrated Production Modelling (IPM) PVT software, PVTP by Petroleum Experts (PETEX) were utilized to characterize the fluid from laboratory data. Then, both black oil model, E100 and compositional model, E300 by Schlumberger were used in the simulation study. Table 1 presents the available data from an actual field in Malay Basin at respected use in proposed workflow as shown in Fig. 2;

Table 1. Available Field Data

Type of Data	Purpose/Activities
Well logs	• Limit reservoir depth and thickness • Record rock properties
Modular Dynamics Tester (MDT)	• Record initial reservoir pressure
Laboratory PVT	• Design fluid model
Drill Stem Test (DST)	• Describe reservoir initial condition • Determine reservoir potential
Gas, condensate, and water production	• Model validation • For history matching
Production rate test	• Quality check flow rate • Define operation condition

The objective of this current work was achieved by following procedures (workflow shown in Fig. 2);

1. Data preparation; check and validate data consistency
2. Fluid characterization from laboratory PVT data
   a. Set up IPM PVTP model
   b. Perform stepwise regression
   c. Match results with laboratory data
3. Generate base case model
4. Simulate depletion process of conventional method; Generalized Pseudo Pressure (GPP) and Velocity Dependent Relative Permeability (VDRP)
5. Simulate depletion process of Enumeration Method
6. Compare and analyze the trend in pressure drop and condensate build-up of the base case, GPP, VDRP, Enumeration Method, and observed field data.

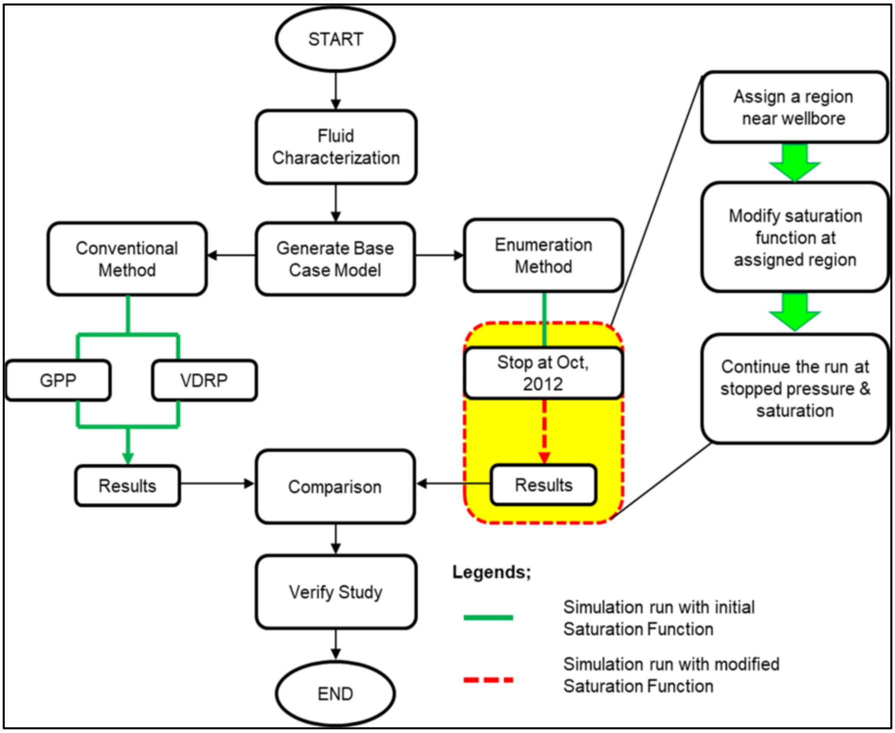

Fig. 2. Study workflow

Fig. 2 presents simulation workflow of this study, starting with characterized the fluid, model construction and developing the base case until the phase where the conventional method and proposed approach was added to the base case in effort to simulate reservoir behavior. The performance of conventional and proposed method was then compared with the observed field data. In the end, the key point of condensate study is always to ensure that the results of the fine grid single well model and/or observed data is matched using a coarse grid model of the same well, where the coarse grid model having the same grid size as the full field [13]–[18].

The conventional method discussed in the study are the GPP and VDRP approach. The GPP and VDRP method were both improving the prediction of gas deliverability and the alterations were focusing at near wellbore. However, in some cases, the material balance is not stable, thus enumeration initialization approach was required to divide the simulation explicitly for the multiple stages.

In the following sections, we illustrate the key aspects of the methodology. A depleted gas condensate reservoir in Malay Basin, known as Reservoir K, was discovered at the depth of approximately 9114 ft at reservoir pressure of 4021 psia and reservoir temperature 306 ^{o}F. Reservoir parameters are summarized in Table. 2.

Table 2. Reservoir input parameter

Parameters	Value
Average Net Thickness (ft)	52.5
Average Porosity	0.19
Average Permeability (mD)	138
Initial Pressure at 9114 ft (psia)	4021
Dew Point Pressure (psia)	4005
Initial Temperature at 9114 ft (F)	306
CGR (STB/MMscf)	15.4 – 16.3
GOR (scf/STB)	65000 – 61350
Gas Specific Gravity	0.8
API (Condensate)	50.2

2.1 Fluid Characterization

A proper characterization of the heavier fractions is necessary in order to decrease CPU time and memory [19]–[21]. Data from laboratory which consist of 39-components had been analyzed on the quality and consistency. It was found that 10-components fluid model (pseudoized from 39-components) matched with the laboratory data, described the reservoir fluid system with good accuracy. This fluid model was utilized in the simulation study.

2.2 Reservoir Model Construction

A single producer well model, Well 5 has been constructed with 7,200 cells. Production was set from 14th October 2008 till 31st December 2013. As the special core analysis was not available, the relative permeability was prepared using Corey function and validated with core data from neighboring field.

The Enumeration Method was simulated by using the black oil model, E100. Meanwhile the GPP and VDRP was executed using compositional simulator, E300 as the features only available in E300 [22].

2.3 Enumeration Method

Enumeration approach was proposed to capture the drastic drop in bottom hole pressure (BHP). Workflow shown in Fig. 2 are the comparison between Enumeration Method and other conventional method simulation process.

Enumerated model was developed from the base case model. Enumeration process allowed initial solution to be reassigned on specific time and the process was repeated till depletion pressure. This method captured the effect of condensate banking to the pressure drop. At the stop, in October 2012, where drastic change was suspected, a region near wellbore in the model was introduced (as shown in Fig. 3). Then, condensate banking parameter such as relative permeability, critical condensate saturation, and capillary number can be modified at the assigned region, while outer region remain as initial condition. The run was then continued at the paused pressure and saturation condition.

In this study, only relative permeability was adjusted at the assigned region (as shown in Fig. 4 and 5), while outer region remain the same initial relative permeability (illustrated in Fig. 3). The modification was applied based on history matching of observed BHP (with controlled production data in Fig. 7, 8, and 9) and PI correlation to represent the permeability-thickness (kh) product reduction.

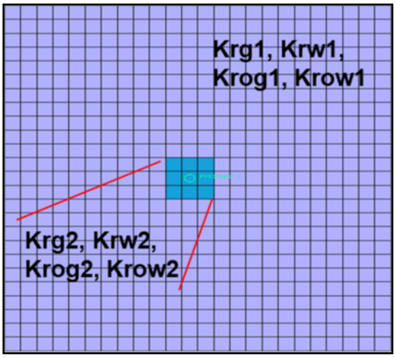

Fig. 3. Condensate bank region in enumerated model

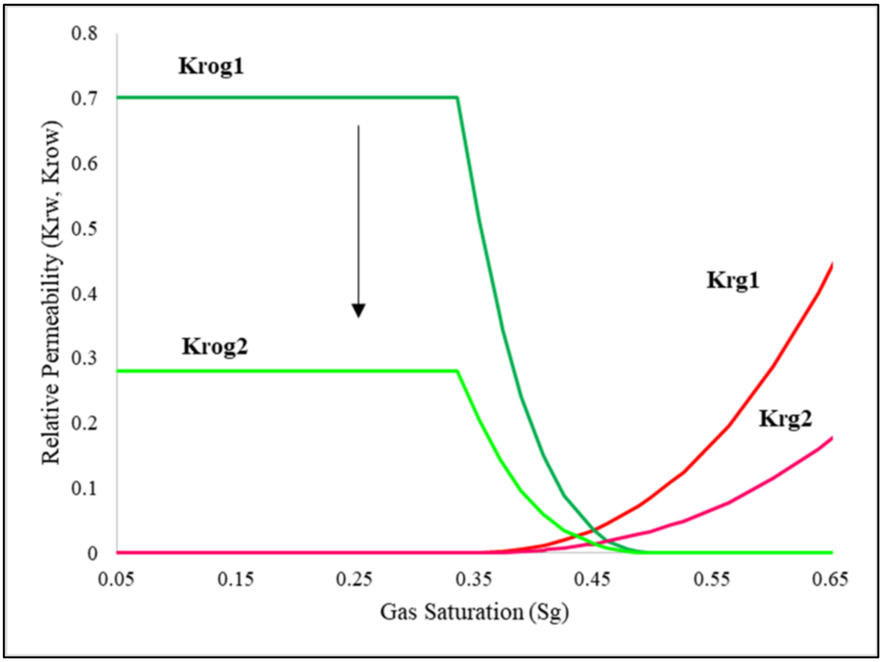

Fig. 4. Shift of oil-gas relative permeability in condensate bank region

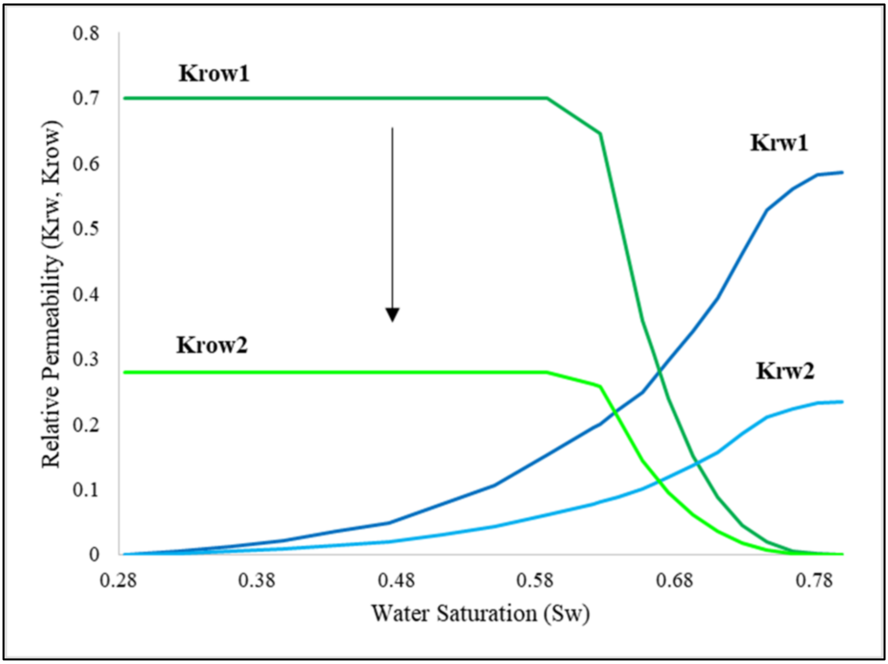

Fig. 5. Shift of oil-water relative permeability in condensate bank region

The different between the conventional and proposed Enumeration Method were the enumeration approach allowed initial solution to be reassigned, for example saturation function, on specific time and the process was continued at the stopped condition. Whereas, conventional methods produced with the initial saturation function throughout the depletion process. The simulation results was then compared and verified with observed data.

3 Results and Discussion

Fig. 6 shows reservoir performance comparison of the base case, GPP, VDRP, and Enumerated Method along with the observed field data, while Fig. 7, 8, and 9 consist of controlled gas production, oil/condensate production, and water production plots. Altogether perform correspondingly in gas and condensate production prediction. Nevertheless, they behave differently in pressure depletion due to different approaches were applied; GPP, VDRP, and Enumeration Method.

Similar trend have been observed in bottom hole pressure plot (as shown in Fig. 6) for both GPP and VDRP as they provide a little effect on the pressure drop. In contrast, Enumeration Method provides a significant changes in pressure that performed close to the observed data. This is thought to be due to different set of relative permeability were used. Thus, the change in relative permeability can be appreciated in pressure behavior description which further supports the pressure drop prediction [23]–[25].

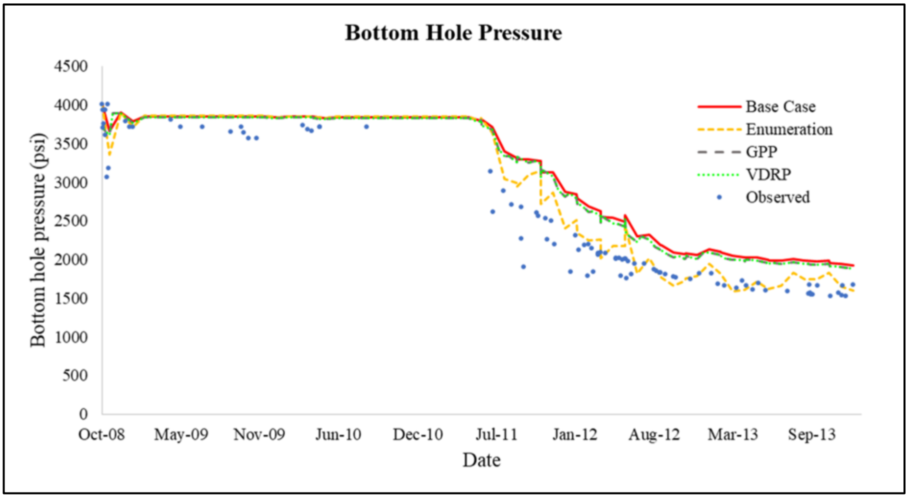

Fig. 6. Reservoir performance comparison of the base case, GPP, VDRP, Enumerated Method, and observed data

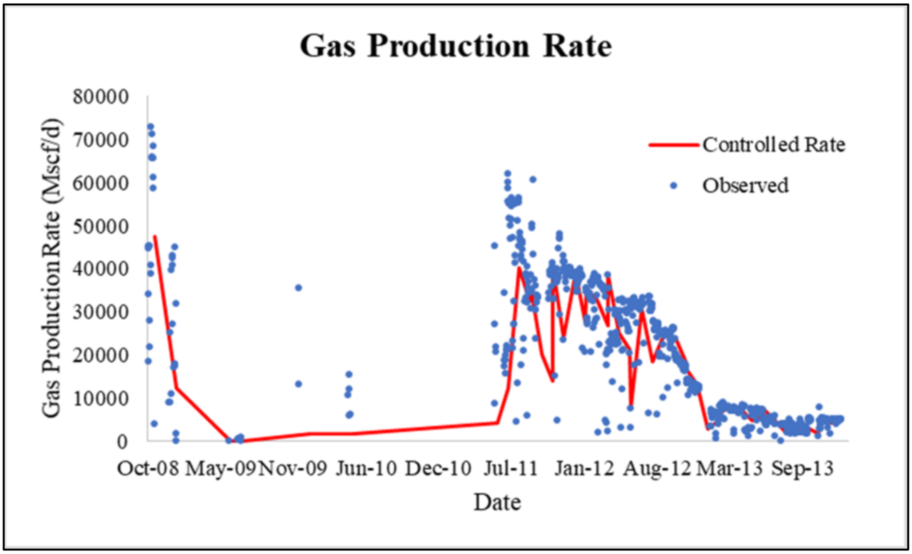

Fig. 7. Gas production controlled rate over observed data for history matching

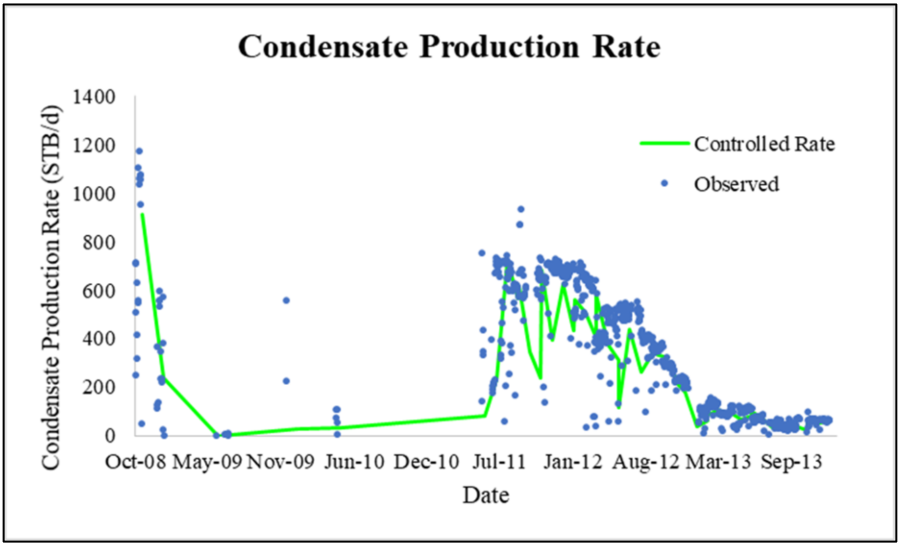

Fig. 8. Condensate production controlled rate over observed data for history matching

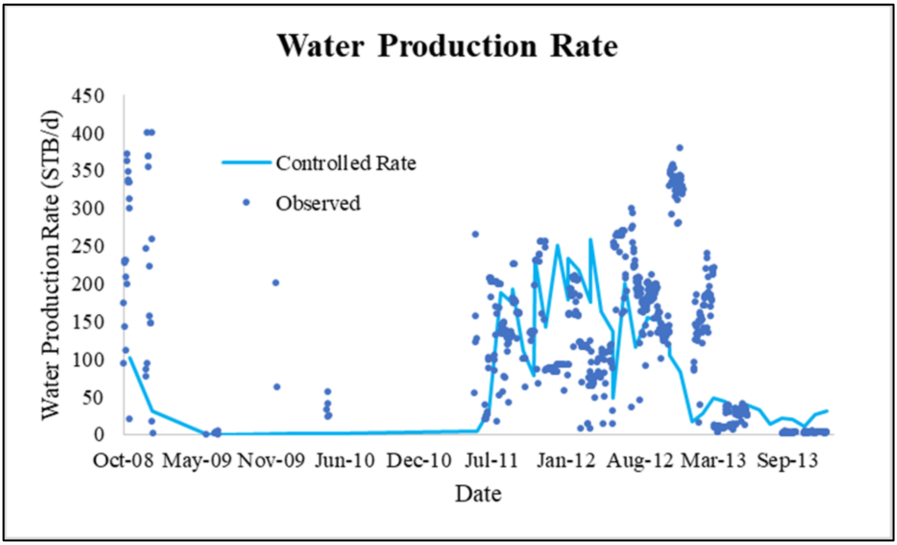

Fig. 9. Water production controlled rate over observed data for history matching

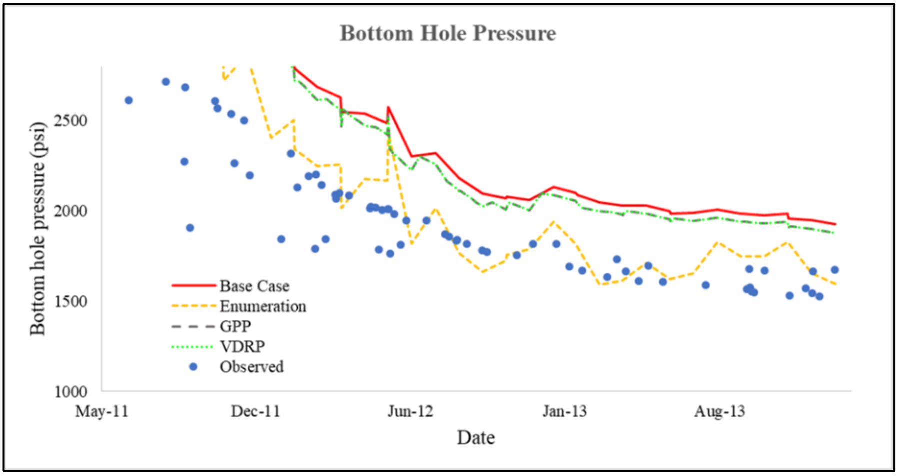

Fig. 10. Bottom hole pressure close up on the base case, GPP, VDRP, Enumerated Method, and observed data

In enumeration process, the shift in relative permeability (as shown in Fig. 4 and 5) is captured to mimic the pressure loss. This pressure loss or additional drawdown is normally seized by positive skin based on analytical analysis. The relative permeability is altered due to condensate accumulation [1]. This concept was supported by Lal (2003), where above the dew point pressure, the gas deliverability is a function of reservoir thickness, permeability, and viscosity. While at pressure below the dew point, the gas deliverability is controlled by the critical condensate saturation and the shape of the gas and condensate relative permeability curves [26]. The relative permeability, which is part of mobility term, may affect the pressure response. Based on this study, the relative permeability performance drop by 50% from the initial model due to condensate banking. The condensate banking accumulation may disrupt the perforated zone and lead to reduction in the initial permeability-thickness (kh) product. Assuming constant absolute permeability and reservoir thickness throughout the depletion process, thus the effective permeability is the only available factor to be altered.

Both GPP and VDRP approaches consider change in relative permeability. However, both methods are incapable to capture drastic pressure drop compared to Enumeration Method. Therefore, for complex system, Enumeration Method is suggested in effort to capture the severe change in pressure behavior.

4 Conclusions

Enumeration Method has been presented to study the effect of condensate banking to the pressure loss. Pressure loss was found to be dependent on relative permeabilities and capillary forces. Consequently, enumeration initialization approach was introduced to improve the condensate bank description and pressure loss calculation. A field data has been utilized in this study to validate the study of increment of pressure drawdown and skin value. It can be consider that this technique provide a detailed information on the development on condensate bank and how it affect the pressure loss. Therefore, for future work, the enumeration initialization approach could be utilized in gas condensate production forecast. In addition, this work could benefit condensate recovery studies as the skin term had been replaced with the relative permeability term that is more physically meaningful.

5 Nomenclature

The symbols as well as the subscripts given here are taken from the SPE Letter and Computer Symbols Standards.

P_p	Pseudo Pressure
P_d	Dew Point Pressure
P_r	Reservoir Pressure
P_{wf}	Bottom-hole Flowing Pressure
K_{rg}	Gas Relative Permeability
K_{ro}	Oil Relative Permeabiltiy
μ_g	Gas Viscosity
μ_o	Oil Viscosity
B_g	Gas Formation Volume Factor
B_o	Oil Formation Volume Factor
R_s	Initial Gas Oil Ratio
S_{wi}	Initial Water Saturation
Bscf	Billion Standard Cubic Feet
MMscf	Million Standard Cubic Feet
CGR	Condensate-Gas-Ratio
GOR	Gas-Oil-Ratio
STB	Stock Tank Barrel

6 References

1. B. Cvetkovic, M. J. Economides, B. Omrcen, and B. Longaric, "Production from Heavy Gas Condensate Reservoirs," in European Petroleum Conference, 1990.
2. J. Kamath, "Deliverability of gas-condensate reservoirs—field experiences and prediction techniques," J. Pet. Technol., vol. 59, no. 4, pp. 94–99, 2007.
3. A. M. AlBaqawi and B. H. Al-Malki, "Well Test Analysis in Naturally Fractured Gas Condensate Reservoirs below Dew Point Pressure," in Asia Pacific Oil and Gas Conference & Exhibition, 2009.
4. A. C. Gringarten, M. Bozorgzadeh, A. Hashemi, and S. Daungkaew, "Well Test Analysis in Gas Condensate Reservoirs: Theory and Practice," in SPE Russian Oil and Gas Technical Conference and Exhibition, 2006.
5. M. Jamiolahmady, M. Sohrabi, S. Ireland, and P. Ghahri, "A generalized correlation for predicting gas–condensate relative permeability at near wellbore conditions," J. Pet. Sci. Eng., vol. 66, no. 3, pp. 98–110, 2009.
6. C. Okporiri and K. I. Idigbe, "Modelling the Effects of Condensate Banking on High CGR Reservoirs," Acad. Res. Int., vol. 5, no. 2, p. 41, 2014.
7. J.-R. Ursin, "Fluid flow in gas condensate reservoirs: the interplay of forces and their relative strengths," J. Pet. Sci. Eng., vol. 41, no. 4, pp. 253–267, 2004.
8. M. Jamiolahmady, A. Danesh, D. H. Tehrani, and D. B. Duncan, "Positive Effect of Flow Velocity on Gas–Condensate Relative Permeability: Network Modelling and

Comparison with Experimental Results," Transp. porous media, vol. 52, no. 2, pp. 159–183, 2003.
9. M. T. Sarvestani, F. Rashidi, and S. A. M. Dehghani, "A production data analysis model for gas/condensate reservoirs," J. Pet. Sci. Eng., vol. 141, pp. 52–69, 2016.
10. A. C. Gringarten, A. Al-Lamki, S. Daungkaew, R. Mott, and T. M. Whittle, "Well test analysis in gas-condensate reservoirs," in SPE annual technical conference, 2000.
11. A. Rahimzadeh, M. Bazargan, R. Darvishi, and A. H. Mohammadi, "Condensate blockage study in gas condensate reservoir," J. Nat. Gas Sci. Eng., vol. 33, pp. 634–643, 2016.
12. Ø. Fevang and C. H. Whitson, "Modeling gas-condensate well deliverability," SPE Reserv. Eng., vol. 11, no. 4, pp. 221–230, 1996.
13. J. W. Barker, "Experience with simulation of condensate banking effects in various gas condensate reservoirs," in International Petroleum Technology Conference, 2005.
14. B. Goktas, N. A. Macmillan, and T. S. Thrasher, "A Systematic Approach to Modeling Condensate Liquid Dropout in Britannia Reservoir," in SPE Latin American and Caribbean Petroleum Engineering Conference, 2010.
15. A. Hashemi, L. Nicolas, and A. C. Gringarten, "Well test analysis of horizontal wells in gas-condensate reservoirs," SPE Reserv. Eval. Eng., vol. 9, no. 1, pp. 86–99, 2006.
16. F. A. Dumkwu, Integrated Reservoir Characterization and Modeling for Enhanced Hydrocarbons Recovery from Mature Gas-condensate Reservoirs: A Case Study of Big Escambia Creek Field, Escambia County, Alabama, USA. University of Alabama Libraries, 2013.
17. L. H. Tan, K. Ghorayeb, R. M. Aziz, and Q. M. Dashti, "Numerical Investigation of Condensate Banking in the North Kuwait Jurassic Gas Condensate Reservoirs," in Kuwait International Petroleum Conference and Exhibition, 2009.
18. M. Ahmadi, M. Sharifi, and A. Hashemi, "Comparison of Simulation Methods in Gas Condensate Reservoirs," Pet. Sci. Technol., vol. 32, no. 7, pp. 761–771, 2014.
19. W. D. McCain, The properties of petroleum fluids. PennWell Books, 1990.
20. J. H. Abou-Kassem, S. M. Farouq-Ali, and M. R. Islam, Petroleum Reservoir Simulations. Elsevier, 2013.
21. C. H. Whitson and M. R. Brulé, Phase behavior. Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers Richardson, TX, 2000.
22. B. Izgec and M. A. Barrufet, "Performance Analysis of Compositional and Modified Black-Oil Models for a Rich Gas Condensate Reservoir," in SPE Western Regional Meeting, 2005.
23. A. M. Al-Shawaf, M. Kelkar, and M. Sharifi, "A New Method to Predict Performance of Gas Condensate Reservoirs," SAUDI ARAMCO J. Technol., p. 23, 2013.
24. S. V. Kolbikov, "Gas-Condensate Recovery For The Low Permeable Sands Gas Cycling Efficiency," in SPE Russian Oil and Gas Conference and Exhibition, 2010.
25. M. Yusof, M. Aslam, I. I. M. Fuad, and A. A. A. A. Matali, "Improved Hydrocarbon Recovery of a Lean Retrograde Gas Reservoir Under Propane Injection," in Abu Dhabi International Petroleum Exhibition and Conference, 2015.
26. R. R. Lal, "Well Testing in Gas-Condensate Reservoirs," STANFORD UNIVERSITY, 2003.